Chapter 4 Cooling System Conversions at Existing Facilities

INTRODUCTION

Reducing the cooling water intake structure's capacity is one of the most effective means of reducing entrainment (and impingement). For the traditional steam electric utility industry, facilities located in freshwater areas that have closed-cycle, recirculating cooling water systems can, depending on the quality of the make-up water, reduce water use by 96 to 98 percent from the amount they would use if they had once-through cooling water systems, though many of these areas generally contain species that are less susceptible to entrainment. Steam electric generating facilities that have closed-cycle, recirculating cooling systems using salt water can reduce water usage by 70 to 96 percent.[1]

Of the 539 existing steam electric power generating facilities that EPA views are potentially subject to the Phase II existing facility proposed rule, 73 of these facilities already have a recirculating wet cooling system (for example, wet cooling towers or ponds).

A closed-cycle recirculating cooling system is an available technology for facilities that currently have once-through cooling water systems. The Agency learned of several examples of existing facilities converting from one type of cooling system to another (for example, from once-through to closed-cycle recirculating cooling system). Converting to a different type of cooling water system, the Agency determined, is significantly more expensive than the technologies on which the performance standards of the proposed rule are based and significantly more expensive than designing new facilities to utilize recirculating systems. EPA has identified four power plants that have converted to closed-cycle recirculating wet cooling tower systems. Three of these facilities--Palisades Nuclear Plant in Michigan, Jefferies Generating Station in South Carolina, and Canadys Station in South Carolina-- converted from once-through to closed-cycle wet cooling tower systems after significant periods of operation utilizing the once-through system. The fourth facility -- Pittsburg Unit 7 – converted from a recirculating spray-canal system to a closed-cycle wet cooling tower system. In this case, the conversion occurred after approximately four years of operation utilizing the original design.

6.1 EXAMPLE CASES OF COOLING SYSTEM CONVERSIONS

Canadys Steam Plant. This 490 MW (nameplate, steam capacity), coal-fired facility with three generating units is located in Colleton County, South Carolina. The first unit initially came online in 1962, the second in 1964, and the third in 1967. All three units operated with a once-through cooling water system for many years. The Canadys Steam plant was converted from a once-through to a closed-cycle recirculating cooling system in two separate projects. Unit 3 (218 MW) was first converted in 1972. Units 1 and 2, both with nameplate capacities of 136 MW, were simultaneously converted from once-through to closed-cycle, a single recirculating wet cooling system in 1992.

The Agency contacted South Carolina Electric & Gas to learn about the cooling system conversions at Canadys

[1] The lower range would be appropriate where State water quality standards limit chloride to a maximum increase of 10 percent over background and therefore require a 1.1 cycle of concentration. The higher range may be attained where cycles of concentration up to 2.0 are used for the design.

(Wicker, 2002). According to plant personnel, the primary motivation for conversion from once-through to recirculating systems related to fresh water availability in both cases. Due to water shortages, the plant chose to convert the cooling systems and avoid water supply and thermal discharge problems.

For the initial cooling system conversion the plant constructed a mechanical-draft, wood cooling tower. The wood tower with design approach of 6 degrees F was refurbished into a fiberglass tower in 1999. The second recirculating cooling system utilizes a concrete mechanical-draft tower, with a design approach of 7 degrees F. For both tower systems, a lack of proximity between the cooling towers and the original intake pumps caused the plant to install new circulating water pumps. The circulating water flows through 84 inch diameter pipes for Unit 3 (with a piping distance of 650 ft from tower to condenser) and 72 inch diameter pipes for the Unit 1, 2 common system (with a piping distance from tower to condenser of 1700 ft). The plant continues to withdraw water through the original intake, although the plant now operates with new intake pumps. In addition, the condensers for each generating unit remained unchanged after the conversions, maintaining the design circulating flow. No condenser problems have emerged due to the recirculating system operation. The principle operational problem for the Canadys Station recirculating system appears to be the quality of the source water, which shows significant algae problems. The station has mitigated this problem through the optimization of tower fill and chemical addition and treatment.(Pearrow, 2001).

The construction of the entire Unit 1, 2 cooling tower system occurred in 8 months. The same information was not available for Unit 3. However, in both cases the cooling system tie-in process lasted approximately 30 days. Although the net downtime was not quantified by South Carolina Power & Light, the owners stated that the tie-in process was scheduled to coincide with planned maintenance outages. Each of the conversions occurred in the Spring, with the Unit 3 tie-in occurring in May of 1972 and that of Unit 1, 2 occurring in roughly May/June of 1992. The Agency has analyzed the historical, monthly-electricity generation for the Canadys Station. The Agency analyzed the generation about the time of the cooling system conversions (specific to the months of, before, and after the conversions). The Agency could not demonstrate that the electricity generation for the months of the conversions differ dramatically from other, non-conversion years. (See DCN 4-2545.)

The Agency inquired of South Carolina Power & Light as to whether they had conducted any historical energy penalty analyses of the cooling system conversions, which they had not. In addition, the Agency did not receive cost information for the cooling tower conversions, outside of the statement from South Carolina Power & Light that it did not experience any significant, unplanned cost overruns for either project.

***Jefferies Coal Units 3 & 4*.** Located in Moncks Corner, South Carolina, this facility has a combined, coal-fired capacity of 346 MW (nameplate, steam). The two coal units (each with 173 MW nameplate capacity) came online in 1970 and operated for approximately 15 years utilizing once-through cooling. Because the U.S. Army Corps of Engineers (USACE) re-diverted the Santee Cooper River, thereby limiting the plant's available water supply, the cooling system was converted from once-through to a closed-cycle recirculating tower system.

The Agency contacted Santee Cooper to learn about the cooling system conversions at Jefferies (Henderson, 2002). The Charleston District of the USACE paid for the construction of the tower system (a common, mechanical-draft, concrete cooling tower unit for both units with a design approach of 10 degree F and a range of 19 degree F) because of the re-diversion of the Santee Cooper River. Both the re-diversion of the river and the construction of the recirculating system occurred between 1983 and 1985. The towers came online in March of 1985. However, the connection of the recirculating system piping to the existing once-through piping occurred in May of 1983, started up in June of 1984, and performance tested in September of 1984. The plant installed valves and a Y-connection in May of 1983, and then continued to operate as a once-through system while the construction of the cooling tower and the re-diversion project finished. After the tower construction and re-diversion had occurred, the Jefferies plant switched the valve over to the recirculating system for full conversion.

The plant was able to utilize the existing circulating water pumps of the Jefferies coal units after the cooling system conversion. However, due to additional pumping head requirements, two small "booster" pumps were added in series after the existing, large circulating water pumps. The plant was able to continue using the original intake without modification, but installed a full new set of intake pumps for the reduced capacity. The condenser flow rate did not change after the conversion. In addition, the plant has not experienced any condenser or tube failure problems as a result of the conversion to a recirculating cooling system. The plant installed new, 108" diameter circulating piping between condenser and tower for a total piping distance of 1700 ft.

Santee Cooper conducted an empirical energy-penalty study over several years to determine the economic impact of the cooling system conversion. Santee Cooper claimed the lost efficiency of the turbines as an economic impact of the closed-cycle cooling system and obtained reimbursement, after significant and extended negotiation, from the USACE. See Chapter 5.6.1 for a discussion of the historical Jefferies Station energy penalty study.

The USACE owns the cooling towers at the Jefferies plant. Because of this arrangement, the USACE has paid for the operation and maintenance (O&M) of the cooling tower system since its construction. The Agency requested historical capital and O&M cost information from the USACE but did not receive it prior to publication of the proposed rule. Because the Agency did not receive the historical O&M information from the plant (which would include the fan and pump operation for the recirculating system), it cannot assess the full energy penalty of the wet cooling tower system at the Jefferies plant.

Palisades Nuclear Generating Plant. Located in Covert, Michigan, the Palisades Nuclear Plant was originally built as an 821 MW (nameplate, steam capacity) plant with a pressurized water reactor, utilizing once-through cooling. The original license for the plant allowed for 700 MW(e) of net generation. The plant is currently rated for 800 MW(e) of power, which is an increase of 100 MW over the initial license, and utilizes a mechanical-draft, wood cooling tower system to condense the steam load of the plant. The plant has replaced the steam generators since originally coming online, and the system now has a nameplate capacity of 812 MW. The plant began operation in early 1972 utilizing the once-through cooling system and subsequently converted to a closed-cycle, recirculating system in May of 1974, when the cooling towers became operational.

Citizen organizations concerned with the impact of the plant on Lake Michigan intervened in the plant's licensing proceedings. The groups sought to limit radioactive releases from the liquid radwaste system and to limit thermal discharges to Lake Michigan (Gulvas, 2002). Through a settlement agreement, the Palisades plant agreed to adopt a recirculating wet system and to make modifications to the radwaste system. Procurement and construction of the cooling tower system began in mid- to late-1971. Consumers Power Company (now known as Consumers Energy) originally designed the cooling system for a once-through, maximum-design intake flow of 486,380 gpm (30,686 L/sec) (Benda and Gulvas, 1976). The plant maintained its original, operating condenser flow of approximately 400,000 gpm after the conversion. The operating intake flow decreased from 405,000 gpm to 78,000 gpm (Consumers Energy, 2001). Because the plant utilized the existing offshore intake without modification for the reduced flow, the intake velocity decreased from 0.5 ft/sec to less than 0.1 ft/sec. The cooling tower system constructed on plant property comprises two tower systems, each with 18 mechanical-draft cells. The system is designed to reduce the water temperature 30 degrees F. The recirculating flow through the system was designed for 410,000 gpm (NRC, 1978).

A modification to cooling tower operation in 1998 resulted in a decreased intake flow rate of 68,000 gpm. In 1999 the plant obtained approval from the Michigan Department of Environmental Quality to increase its intake flow rate, and has operated with an intake from Lake Michigan of approximately 100,000 gpm since the approval. The plant sought to obtain the intake flow rate increase in order to improve electrical generation efficiency (Consumers Energy, 2001). Subsequently, the cooling water circulation through the condensers increased to 460,700 gpm, but the cooling tower flow rate remained the same (Gulvas, 2002).

The conversion process at Palisades utilized the original, offshore intake for the reduced flow rates in addition to the original 3,300-feet long, 11-feet diameter intake piping. However, the plant installed new intake pumps and removed two traveling screens to install additional "dilution" pumps for the recirculating system. The plant also installed entirely new circulating water pumps to convey water between the condenser and tower systems. The Agency learned initially from Consumers Energy that the original once-through pumps might have been utilized for the recirculating system (DCN 4-2502). However, Consumers Energy's follow-up research indicated that the historical conversion required new circulating pumps due to increased pumping head. Although the plant chose to install the relatively low-head, mechanical-draft cooling towers, the converted system required enough additional power from the pumps in order to warrant full replacement.[2]

The circulating water flow rate through the condensers did not change from before to after the cooling system conversion (though the intake flow rate increase in 1999 apparently increased condenser flow). The plant made no modifications to the condenser in order to accommodate the recirculating system, despite the original once-through design. However, prior to operation with the recirculating system, a significant portion of the condenser tubes had begun to fail. The tubes were failing with the once-through system due to vibration. After conversion of the cooling system, the plant continued to operate with condenser leaks, thereby raising SO_4 levels in the generators. This led to more time necessary to bring the levels in line with specifications before power escalation with the cooling system operating in recirculating mode. After conversion to the recirculating system, the condenser tubes were replaced.
The Agency concludes that the choice of installation of mechanical-draft towers, as opposed to the more traditional nuclear design of natural-draft towers, at the Palisades Nuclear Plant may have been, in part, to minimize the plume migration from the system. The plant is located along a scenic portion of Lake Michigan, in close proximity to sensitive lakeside vegetation and nearby orchards. In addition, within a half-mile of the plant is a highway. According to Consumers Energy, the plant has not experienced any problems with the plumes from the mechanical-draft units interfering with the nearby highway, nor with boating and recreation on the lake (DCN 4-2502). However, vegetation within 90 meters of the towers was damaged by frost induced by the tower plumes. The NRC estimates that drift from the Palisades cooling towers (built with drift eliminators and splash fill) deposits within short distances from the towers, all within 800 feet and 70 percent within 300 feet (NRC, 1978).

The Palisades plant constructed the main portions of the tower system in 1972 and 1973, while the plant operated in once-through mode. Construction finished by early 1974. In August of 1973 the plant experienced the beginning of a sizeable outage (ten months), which according to Consumers Energy was due primarily to the connection and testing of the recirculating system. The Agency had initially learned from a journal article that the plant was off-line for a variety of maintenance outages, which the Agency interpreted as being mostly unrelated to the cooling tower system.[3]

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[2] According to cooling tower bid descriptions from three reputable cooling tower manufacturers, the typical total dynamic head requirements of a mechanical draft cooling tower unit is approximately 30 feet. See DCN 4-2501.

[3] Benda, R.S. and J. Gulvas, 1976, states "the plant was shutdown because of various operational problems in August 1973." In addition, during a conference call with the Agency regarding the cooling system conversion,

However, in a letter submitted to the Agency, Consumers Energy stated, "it appears that the outage was primarily for the purpose of installing the new circulating water system and the modifications necessary for its operation." Through research into the historical electricity generation of the plant, the Agency confirms that the outage of ten-months occurred (see DCN 4-2545). However, the Agency notes that it was unable to obtain specific records to show the cause(s) of the outage. The Agency also notes that part of the settlement agreement called for modifications to the radwaste system. In addition, plant operation prior to the conversion had shown problems with the condenser.

The final installed cost of the project was $18.8 million (in 1973-1974 dollars), as paid by Consumers Energy. The key items for this project capital cost included the following: two wood cooling towers (including splash fill, drift eliminators, and 36-200 hp fans with 28 ft blades); two circulating water pumps; two dilution water pumps; startup transformers; yard piping for extension of the plant's fire protection system; modifications to the plant screenhouse to eliminate travelling screens and prepare for installation of the dilution pumps; a new discharge pump stucture with pump pits; a new pumphouse to enclose the new cooling tower pumps; yard piping for the circulating water system to connect the new pumphouse and towers; switchgear cubicles for the fans; roads, parking lots, drains, fencing, and landscaping; and a chemical additive and control system. Additionally, Consumers Energy estimates that the plant abandoned approximately $683,000 (1973/1974 dollars) of original plant equipment. Excluding the sunk costs of the abandoned equipment, the project cost is $58.5 in year 2001 dollars (the cost basis of this proposed rule) or $55.9 in year 1999 dollars (the dollar basis of facility level cost estimates discussed in Chapter 2 of this document). Frequently, in historical studies of cooling system conversions, the cost basis has been presented as dollars per kW. If the Palisades conversion project were presented on such a basis, the ratio would be $68 per kW (1999 $ per kW of nameplate capacity). Utilizing the EPA methodology presented in Chapter 2 for assessing cooling tower "retrofits" gives an estimated installed capital cost of $68 per kW (1999 $) for a nuclear site with the original design characteristics of Palisades.

The Agency learned that Consumers Energy believes that the cooling tower system at Palisades has a significant impact on the efficiency of the plant's generating unit. See Chapter 5.6.3 for a discussion of the Palisades estimates of energy penalty impacts from the operation of cooling towers.

Pittsburg Power Plant, Unit 7. Located in Contra Costa County, California, this 751 MW (nameplate, gas-fired steam) unit was originally constructed with a recirculating canal cooling system. The plant began operation in 1972 and converted to a system with mechanical-draft cooling towers in 1976. The original spray canal system, according to plant personnel, did not operate efficiently enough for the plants needs (DCN 4-2554). The plant then constructed the mechanical-draft cooling tower system between two reaches of the original canal. Because of the proximity of the cooling towers to the original circulating piping that serviced the canal, the plant was able to utilize the majority of this existing circulating piping system with the converted design. The construction of the cooling towers occurred on a very narrow strip of land between the canals. The location provides minimal buffer land surrounding the towers, and indicates that the site required significant prepartion work. The cooling towers extend along the canal divider from about 300 meters away from the generating unit buildings to approximately 800 meters. The mechanical-draft towers consist of two units, each with 13 cells. The water supply used in the system is brackish water from Suisun Bay. The cooling system conversion utilized the existing condenser in addition to the conduit system. The design condenser flow is 352,000 gpm. The plant's design intake flow rate is 20,200 gpm (EEI, 1994).

Consumers Energy stated that operational problems unrelated to the conversion process had been mostly responsible for the extended outage (see DCN 4-2502).

Pacific Gas & Electric, former owners of the Pittsburg Power Plant, reported the total project cost for the cooling conversion at Pittsburg Unit 7 as $16.7 million (1976 $) (DCN 4-2506). This corresponds to $40.87 million in 1999 dollars or $54 per kW (1999 $ per kW of nameplate capacity). Because the plant is in Contra Costa County, California, the cost of construction in this area may not be representative of other areas of the country. The Oakland, California area has a city construction multiplier of approximately 1.19 according to a cost estimating reference (R.S. Means, 2000). Therefore, the costs for the Pittsburg Unit 7 conversion on a national average basis would be approximately $34.4 million for total project capital cost (in 1999 $) or $46 per kW (1999 $ per kW of nameplate capacity). Utilizing the EPA methodology presented in Chapter 2 for assessing cooling tower "retrofits" gives an estimated installed capital cost of $38 per kW (1999 $, national-average cost basis) for a site with the characteristics of Pittsburg Unit 7.

Dry Cooling Conversion Projects. At the time of this proposal, the Agency is unaware of demonstrated cases of cooling system conversions involving dry cooling systems for the size of power plants within the scope of this proposed rule. See Appendix D of this document for a discussion of dry cooling systems and their applicability for retrofit designs.

4.2 Plant Outages for Cooling System Conversions

For three of the cooling system conversion cases examined above, the Agency obtained information from the plants regarding the gross outage duration for converting between cooling system types. The duration of the outages reported to the Agency were 83 hours (gross) for the Jefferies Station, 30 days (gross) for each of the two Canadys conversions, and 10 months (gross) for Palisades Nuclear. The Agency examined historical electricity generation data for these plants and could infer that these outages did occur. However, due to the historical nature of the projects (that is, conversions that occurred from 10 to 30 years ago), the Agency found the documentation of the engineering aspects of the conversions to be limited. For the more recent projects – Jefferies and Canadys Unit 3 – the Agency received information directly from members of the plant staff that participated in, or were employed at the stations during the conversions. For Palisades, the Agency received a significant historical information about the plant, but limited information relating to the specifics of the plant outage for the cooling system conversion.

Based on these limited data points provided to the Agency, conclusions as to the expected duration of outages for a variety of cooling system conversions cannot be conclusively drawn. The only substantial conclusion the Agency can reach is that the gross duration of the outage varies widely, based on the data reported to the Agency, and that the possibility exists for both extremely short outages and those of extremely long duration. The Agency based the economic analysis of the regulatory options summarized in Section 4.3 on a gross outage of one-month per converted plant. The Agency based this estimate on the information it had received from Jefferies and Canadys stations and research into other projections (see below). The Agency did not receive the Palisades information until very late in the development of this proposed rule. Based on the information provided to the Agency (including the late Palisades submission), the estimate of one-month could in some cases over- and others under-estimate the expected outage duration for a cooling system conversion. In addition, there is some evidence that the durations of outages may differ based on fuel type (that is, nuclear versus non-nuclear).

As mentioned above, the Agency researched outage projections from historical 316 demonstrations, where plants conducted engineering studies as to the duration of the expected outage for a site-specific cooling system conversion. Appendix VIII-3 of the Draft Environmental Impact Statement (DEIS) for Bowline Point, Indian Point 2 & 3, and Roseton Generating Stations (Power Tech Associates, 1999) estimates net outage durations for an evaluation of four closed-cycle cooling projects. The DEIS states, "plants must be shut down for construction and commissioning beyond the normal shutdowns of the plants. In the cases of Roseton and Bowline, this period was estimated at one month beyond normal outages." For the two nuclear units of Indian Point, the authors estimate two outages for each unit, with each outage lasting 4 months. The DEIS states that the basis of the longer estimates for the nuclear plants is as follows: "the safety issues have to be addressed during excavation (particularly when blasting is required), tying the new system into the plant, and the extensive testing which must follow." The DEIS estimates that the separate blasting and tying-in outages would last four months each, considerably longer than for the fossil-fueled Bowline Point and Roseton Stations. The Agency notes that there is no detailed engineering basis (such as detailed descriptions of the types of connections to be made, etc.) given by the Authors for any of the projections made in Appendix VIII-3 of the 1999 DEIS.

The Agency also consulted a detailed historical proposal for a Roseton Generating Station cooling system conversion (Central Hudson Gas & Electric, 1977). The report estimates a gross outage period of one-month for the final pipe connections for the recirculating system. The report estimates the net outage as 10 days for one of the two units and no downtime for the second. The reason for the short estimates of downtime are due to the coincidence of the connection process with planned winter maintenance outages. Unlike the projection in the 1999 DEIS described above, this 1977 projection was accompanied by a relatively detailed description of the expected level of effort and engineering expectations for connecting the reciruclating system to existing equipment.

The Agency learned from the NPDES permit application for Salem Generating Station estimates that outages due to construction and conversion to cooling towers are expected to last 7 months per generating unit, in addition to the station's planned outages for refueling (see Appendix F, Attachment 8 of the 1999 PSE&G Permit Application for Salem Generating Station, Permit No. NJ0005622).

In addition, the Agency consulted a variety of sources to determine the typical occurrence and duration of planned maintenance outages. As noted in the example cases described in Section 4.1 above, each of the cooling system conversions coincided with planned maintenance outages. Appendix VIII-2.A of the DEIS for the fossil-fuel Roseton Station states, "a review of historical data indicates that there has[sic] been 30 day maintenance outages occurring nominally from mid-Sept. to mid-Oct."

The 1999 Permit Application for Salem predicts a three year refueling cycle for each unit that is accompanied by outages of approximately 60 days one year, 40 days in a second year, and no outage in the third. This data is consistent with other information the Agency obtained from literature. The Agency learned that for 2000 the industry mean nuclear refueling outage was approximately 40 days (Nucleonics Week, January 18, 2001). In addition, NUREG-1437 shows that nuclear plants undergo periodic and predictable outages for inspections. The following excerpts from NUREG-1437 explain the NRC's view of outages at nuclear plants:

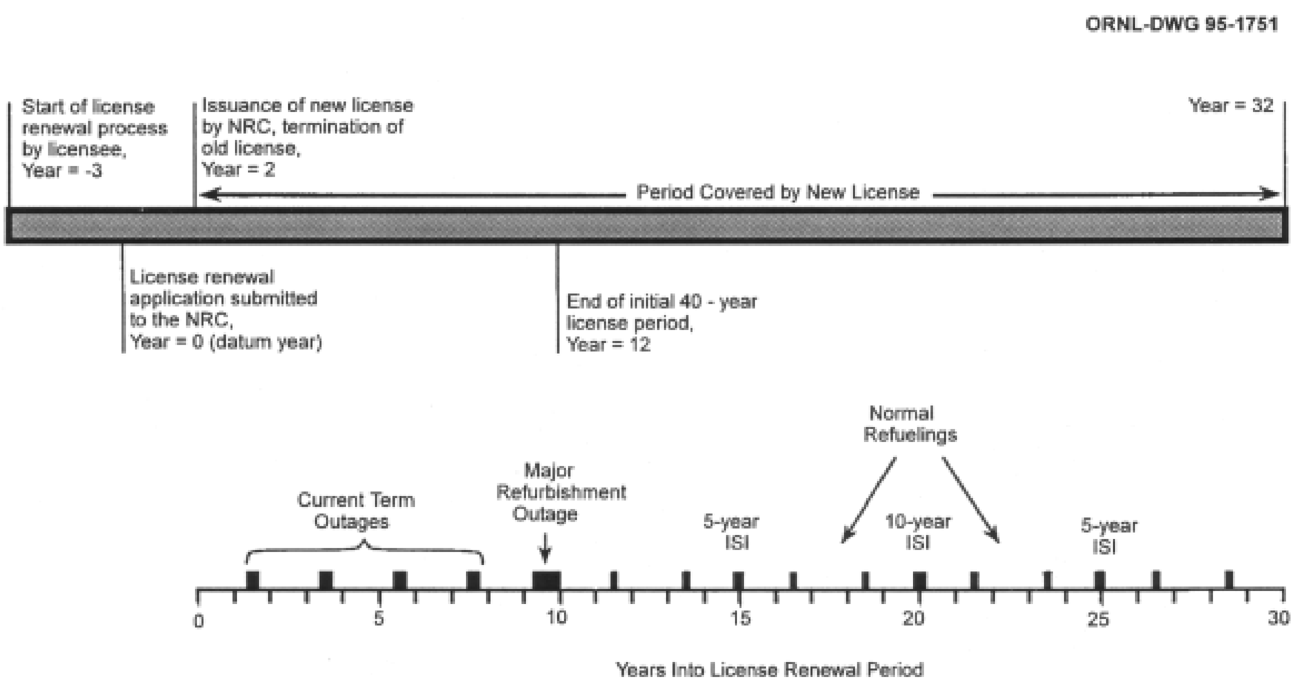
From Section 2.2.6-

> Nuclear power plants must periodically discontinue the production of electricity for refueling, periodic in-service inspection (ISI), and scheduled maintenance. Refueling cycles occur approximately every 12 to 18 months. The duration of a refueling outage is typically on the order of 2 months. Enhanced or expanded inspection and surveillance activities are typically performed at 5- and 10-year intervals. These enhanced inspections are performed to comply with Nuclear Regulatory Commission (NRC) and/or industry standards or requirements such as the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. Five-year ISIs are scheduled for the 5th, 15th, 25th, and 35th years of operation, and 10-year ISIs are performed in the 10th, 20th, and 30th years. Each of these outages typically requires 2 to 4 months of down time for the

plant. For economic reasons, many of these activities are conducted simultaneously (e.g., refueling activities typically coincide with the ISI and maintenance activities).

Many plants also undertake various major refurbishment activities during their operational lives. These activities are performed to ensure both that the plant can be operated safely and that the capacity and reliability of the plant remain at acceptable levels. Typical major refurbishments that have occurred in the past include replacing PWR steam generators, replacing BWR recirculation piping, and rebuilding main steam turbine stages. The need to perform major refurbishments is highly plant-specific and depends on factors such as design features, operational history, and construction and fabrication details. The plants may remain out of service for extended periods of time, ranging from a few months to more than a year, while these major refurbishments are accomplished. Outage durations vary considerably, depending on factors such as the scope of the repairs or modifications undertaken, the effectiveness of the outage planning, and the availability of replacement parts and components.

Each nuclear power plant is part of a utility system that may own several nuclear power plants, fossil-fired plants, or other means of generating electricity. An on-site staff is responsible for the actual operation of each plant, and an off-site staff may be headquartered at the plant site or some other location. Typically, from 800 to 2300 people are employed at nuclear power plant sites during periods of normal operation, depending on the number of operating reactors located at a particular site. The permanent on-site work force is usually in the range of 600 to 800 people per reactor unit. However, during outage periods, the on-site work force typically increases by 200 to 900 additional workers. The additional workers include engineering support staff, technicians, specialty craftspersons, and laborers called in both to perform specialized repairs, maintenance, tests, and inspections and to assist the permanent staff with the more routine activities carried out during plant



outages.

License renewal schedule and outage periods considered for environmental impact initiator definition,

Figure 2.3 from NUREG-1437, Volume I.

The Agency also found information on outage information contained in the April, 2001 accounting report for Mirant, Corp. (form 8K, April 27, 2001). The report gave the following information on planned outages at Mirant's California fossil-fueled power plants:

> Major maintenance is presently scheduled on a three-year cycle for the boilers and a 6-year interval for the steam turbine-generators. The overhaul duration is typically six to eight weeks, depending on the scope of the work to be performed. Virtually all of the Mirant California Facilities' major maintenance for the next few years will be performed during outages dictated by the installation of SCR systems or low-NO(X) burners, both to reduce NO(X) emissions.
>
> Major outages are scheduled for Contra Costa Units 6 and 7 in 2000-2001 to install systems to reduce stack emissions. Low-NO(X) burners were recently installed on Contra Costa Unit 6. Contra Costa Unit 7 is scheduled for installation of a SCR system from March to June of 2001 with Contra Costa Unit 6 SCR installation scheduled for 2003.
>
> Major outages are scheduled for Pittsburg Units 1 through 7 within the next three years to install systems to reduce stack emissions or correct equipment concerns that are affecting reliability. Pittsburg Units 1 through 4 will retube the condensers and perform boiler repair work in 2001. Pittsburg Units 5 and 6 just completed installation of low-NO(X) burners and are scheduled to install SCRs in 2001-2002. Pittsburg Unit 7 is scheduled to install an SCR in 2003. The SCR outages will be between 14 and 20 weeks long.
>
> Potrero Unit 3 will have two major outages in the next four years, 2001 to retube the condenser and make boiler repairs as necessary and 2004 to install an SCR. The scheduled duration of these outages is 10 and 20 weeks respectively.

The Agency located a reference for a project where four condenser waterboxes and tube bundles were removed and replaced at a large nuclear plant (Arkansas Nuclear One). The full project lasted approximately 2 days. The facility, based on experience, had estimated the full condenser replacement to occur over the course of 8 days. Even though the scope of condenser replacements differ from potential cooling system conversions, the regulatory options considered for flow reduction commensurate with wet cooling anticipate that a subset of conversions would precipitate condenser tube replacements. As such, the condenser replacement schedule is important to the consideration of select cooling system conversions.

4.3 Summary of Flow-Reduction Options Considered

The Agency examined regulatory options based on intake flow reduction at in-scope, existing power plants for the proposed rule. The following summaries describe the three wet cooling based options considered by the Agency.

Intake Capacity Commensurate with Closed-Cycle, Recirculating Cooling System for All Facilities

EPA considered a regulatory option that would require Phase II existing facilities having a design intake flow 50 MGD or more to reduce the total design intake flow to a level, at a minimum, commensurate with that which can be attained by a closed-cycle recirculating cooling system using minimized make-up and blowdown flows. In addition, facilities in specified circumstances (for example, located where additional protection is needed due to concerns regarding threatened, endangered, or protected species or habitat; migratory, sport or commercial species of concern) would have to select and implement design and construction technologies to minimize impingement mortality and entrainment. This option does not distinguish between facilities on the basis of the waterbody from which they withdraw cooling water. Rather, it would ensure that the same stringent controls are the nationally applicable minimum for all waterbody types. This is the regulatory approach EPA adopted for new facilities. As stated above, 73 of the facilities potentially subject to this proposed rule already utilize a recirculating wet cooling system (e.g., wet cooling towers or ponds). These facilities would meet the requirements under this option unless they are located in areas where the director or fisheries managers determine that fisheries need additional protection. Therefore, under this option, 466 steam electric power generating facilities would be required to meet performance standards for reducing impingement mortality and entrainment based on a reduction in intake flow to a level commensurate with that which can be attained by a recirculating, closed-cycle wet system.

EPA did not select closed-cycle, recirculating cooling systems as the best technology available for existing facilities because of the generally high costs of such conversions. According to EPA's cost estimates, capital costs for individual high-flow plants to convert to wet towers generally ranged from 130 to 200 million dollars, with annual operating costs in the range of 4 to 20 million dollars. EPA estimates that the total annualized post-tax cost of compliance for this option is approximately $2.26 billion. Not included in this estimate are 9 facilities that are projected to be baseline closures. Including compliance costs for these 9 facilities would increase the total cost of compliance with this option to approximately $2.32 billion. EPA also has serious concerns about the short-term energy implications of a massive concurrent conversion and the potential for supply disruptions that it would entail.

The estimated annual benefits (in $2001) for requiring all Phase II existing facilities to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems are $83.9 million per year and $1.08 billion for entrainment reductions.

Intake Capacity Commensurate with Closed-Cycle Wet Cooling Systems for All Facilities on Oceans, Estuaries, and Tidal Rivers

EPA considered an alternate technology-based option in which closed-cycle, recirculating cooling systems would be required for all facilities on certain waterbody types. Under this option, EPA would group waterbodies into the same five categories as in today's proposal: (1) freshwater rivers or streams, (2) lakes or reservoirs, (3) Great Lakes, (4) tidal rivers or estuaries; and (5) oceans. Because oceans, estuaries and tidal rivers contain essential habitat and nursery areas for the vast majority of commercial and recreational important species of shell and fin fish, including many species that are subject to intensive fishing pressures, these waterbody types would require more stringent controls based on the performance of closed-cycle, recirculating cooling systems. EPA discussed the susceptibility of these waters in a Notice of Data Availability (NODA) for the new facility rule (66 FR 28853, May 25, 2001) and invited comment on documents that may support its judgment that these waters are particularly susceptible to adverse impacts from cooling water intake structures. In addition, the NODA presented information regarding the low susceptibility of non-tidal freshwater rivers and streams to impacts from entrainment from cooling water intake structures.

Under this alternative option, facilities that operate at less than 15 percent capacity utilization would, as in the proposed option, only be required to have impingement control technology. Facilities that have a closed-cycle, recirculating cooling system would require additional design and construction technologies to increase the survival rate of impinged biota or to further reduce the amount of entrained biota if the intake structure was located within an ocean, tidal river, or estuary where there are fishery resources of concern to permitting authorities or fishery managers.

Facilities with cooling water intake structures located in a freshwater (including rivers and streams, the Great Lakes and other lakes) would have the same requirements as under the proposed rule. If a facility chose to comply with Track II, then the facility would have to demonstrate that alternative technologies would reduce impingement and entrainment to levels comparable to those that would be achieved with a closed-loop recirculating system (90% reduction). If such a facility chose to supplement its alternative technologies with restoration measures, it would have to demonstrate the same or substantially similar level of protection. (For additional discussion see the new facility final rule 66 FR 65256, at 65315 columns 1 and 2.)

EPA has estimated that there are 109 facilities located on oceans, estuaries, or tidal rivers that do not have a closed cycle recirculating system and would be required to meet performance standards for reducing impingement mortality and entrainment based on a reduction in intake flow to a level commensurate with that which can be attained by a closed-cycle recirculating system. The other 430 facilities would be required to meet the same performance standards in the in today's proposal.

The potential environmental benefits of this option have been estimated at $87.8 million and $1.24 billion for entrainment reductions annually. Although this option is estimated (a full cost analysis was not done for this option) to be less expensive at a national level than requiring closed-cycle, recirculating cooling systems for all Phase II existing facilities, EPA is not proposing this option. Facilities located on oceans, estuaries, and tidal rivers would incur high capital and operating and maintenance costs for conversions of their cooling water systems. Furthermore, since impacted facilities would be concentrated in coastal regions, there is the potential for short-term energy impacts and supply disruptions in these areas. EPA also invites comment on this option.

Intake Capacity Commensurate with Closed-Cycle, Recirculating Cooling System Based on Waterbody Type

EPA also considered a variation on the above approach that would require only facilities withdrawing very large amounts of water from an estuary, tidal river, or ocean to reduce their intake capacity to a level commensurate with that which can be attained by a closed-cycle, recirculating cooling system.

For example, for facilities with cooling water intake structures located in a tidal river or estuary, if the intake flow is greater than 1 percent of the source water tidal excursion, then the facility would have to meet standards for reducing impingement mortality and entrainment based on the performance of wet cooling towers. These facilities would have the choice of complying with Track I or Track II requirements. If a facility on a tidal river or estuary has intake flow equal to or less than 1 percent of the source water tidal excursion, the facility would only be required to meet the performance standards in the proposed rule. These standards are based on the performance of technologies such as fine mesh screens and traveling screens with well-designed and operating fish return systems. The more stringent, closed-cycle, recirculating cooling system-based requirements would also apply to a facility that has a cooling water intake structure located in an ocean with an intake flow greater than 500 MGD.

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